STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2001-232

November 14, 2001

MAINE PUBLIC UTILITIES COMMISSION
Investigation of Central Maine Power
Company's Stranded Cost Revenue
Requirement

BENCH ANALYSIS
(REDACTED)

I. INTRODUCTION

On August 16, 2001, the Advisory Staff submitted its Phase I Bench Analysis in the above-referenced matter in response to the Central Maine Power Company's Phase I filing of July 16, 2001.

On October 3, 2001, the Company submitted its Phase II direct case as well as its response to the Phase I Bench Analysis. Based on the Company's response it appears that the Phase I portion of the case served its intended purpose of identifying and narrowing the issues in the case.

The Advisory Staff submits this Phase II Bench Analysis to present its independent analysis on certain issues (e.g., the sales forecast) as well as providing the parties with its view, at this point in the case, on the other ratemaking and policy issues as a means of both facilitating settlement discussions as well as presentation of the issues at the hearing stage should the case be fully litigated. Given the very nature of the issues involved, the most detailed part of this analysis concerns the Company's sales forecast for the rate effective period. In presenting this analysis, the Advisory Staff, where possible has attempted to use actual numbers. In certain instances, due to both time constraints and/or unavailability of information this was not possible. In such

cases, we have tried to describe our position on the particular issue in sufficient detail to aid the process and to describe what facts we believe still must be developed.

As we have in prior bench analyses, the Advisory Staff would note that any views and positions expressed here are preliminary and based on the information presented to date. The final recommendations in the case will be presented in the Examiner's Report scheduled to be filed January 29, 2002 and will be based on the record developed at the hearings scheduled to be held in mid-December.

II. RATE EFFECTIVE PERIOD

CMP has proposed that stranded cost rates in this case be set for a three-year rate effective period which is commensurate with the Company's recent generation entitlement sale. We agree with the three-year approach proposed by the Company with certain caveats.

First, as we discuss in Section III.D., a deferral mechanism which provides protection to both ratepayers and shareholders if QF outages are substantially different than projected should be adopted as part of this proceeding.

Second, as discussed in Section III, given current political and economic conditions, it is extremely difficult to forecast sales at this time with any degree of certainty. Therefore, it should be understood at the outset that although rates are being set assuming a three-year rate effective period, during that time period the Commission may on its own motion, or pursuant to a request of any party in this matter or other directly affected person, initiate an investigation to reset stranded cost rates consistent with the provisions of 35-A M.R.S.A. § 3208.

Third, to ensure that the Commission can fulfill its obligations under section 3208, the Company we recommend that CMP be required to file quarterly reports with the Commission detailing the level of its electricity sales as well as the amount of stranded cost revenue, from both core and non-core customers, during that quarter as well as the past year.

III. SALES FORECAST

A. Introduction

1. Summary of Recommendations

The general approach in this Bench Analysis has been to accept the overall sales forecast methodology developed by CMP and to make adjustments to inputs for the future price of electricity, future economic conditions in the CMP service territory, DSM, and appliance characteristics. We have developed revised CMP sales forecasts in two Bench Analysis scenarios with respect to interviews conducted by CMP to establish sales in the commercial and industrial classes. In the first scenario, we accept the CMP interview results. In the second scenario, we assume that the sales forecasts are derived from forecasts of general economic conditions rather than from the non-paper industry customer interviews.

The Bench Analysis of CMP sales is organized by first presenting a summary of the results. After describing the overall sales differences that result from our adjustments, we discuss our approach and details of the adjustments. We first describe the general approach of adjusting CMP's forecast rather than applying a different trend or econometric approach. Next, we review background information as a context for the adjusted sales forecast including a comparison between the sales forecast developed in Docket No. 97-580 and actual sales. Much of the Bench Analysis describes adjustments to CMP's sales forecast for price projections, price elasticity factors, economic growth, appliance characteristics, DSM and pulp and paper industry assumptions.

We have presented summary results of the Bench Analysis on two tables below. The first table presents a summary of total electricity sales for CMP as projected by the Company and as adjusted in the Bench Analysis with and without accepting the interview data for commercial and industrial customers. The second table summarizes the comparative results for the Bench Analysis versus CMP's analysis on a class by class basis. A more comprehensive summary of the adjustments to each forecast is presented at the end of this document.

	CMP Residential	Bench Analysis Residential	Percent Bench Above CMP	CMP Commercial	Bench Analyis of Commercial without CMP Interviews	Percent Bench Above CMP	Bench Analyis of Commercial with CMP Interviews	Percent Bench Above CMP	CMP Industrial	Bench Analyis of Industrial without CMP Interviews	Percent Bench Above CMP	Bench Analyis of Industrial without CMP Interviews	Percent Bench Above CMP	CMP Paper	Bench Analysis Paper	Percent Bench Above CMP
2001	3,025.2	3,028.8	0.12%	2,900.0	2,819.9	-2.76%	2,834.1	-2.27%	1,557.5	1,564.1	0.42%	1,557.4	0.00%	1,620.0	1,629.6	0.59%
2002	2,968.5	3,061.5	3.13%	2,964.9	2,896.9	-2.30%	2,895.8	-2.33%	1,558.0	1,639.8	5.25%	1,562.8	0.31%	1,578.1	1,611.8	2.14%
2003	2,985.3	3,164.7	6.01%	3,078.3	3,108.7	0.99%	3,080.7	0.08%	1,604.4	1,717.9	7.07%	1,624.1	1.23%	1,578.9	1,612.0	2.10%
2004	3,013.0	3,275.9	8.72%	3,172.7	3,275.1	3.23%	3,224.4	1.63%	1,647.1	1,771.7	7.57%	1,678.3	1.89%	1,579.7	1,612.2	2.06%
2005	3,035.8	3,376.2	11.21%	3,251.6	3,452.3	6.17%	3,372.5	3.72%	1,695.1	1,820.4	7.39%	1,730.8	2.11%	1,580.5	1,612.4	2.02%
2006	3,067.1	3,464.8	12.97%	3,333.8	3,570.6	7.10%	3,476.7	4.29%	1,722.2	1,880.4	9.19%	1,757.6	2.05%	1,231.4	1,262.6	2.54%

Projection of Total Sales to Residential, Commercial, Industrial and Other Customers

	Retail Sales in GWH			Annual Percent Change in Electricity			Percent Bench Analysis	
	CMP Forecast	Bench Analysis Forecast Using CMP Interview Data	Bench Analysis Forecast Without CMP Interview Data	CMP Forecast	Bench Analysis Forecast Using CMP Interview Data	Bench Analysis Forecast Without CMP Interview Data	Bench Analysis Forecast Using CMP Interview Data	Bench Analysis Forecast Without CMP Interview Data
2001	9,137.9	9,085.0	9,077.5	-3.08%	-3.64%	-3.72%	-0.58%	-0.66%
2002	9,104.7	9,167.1	9,245.2	-0.36%	0.90%	1.85%	0.69%	1.54%
2003	9,282.1	9,516.9	9,638.6	1.95%	3.82%	4.26%	2.53%	3.84%
2004	9,447.9	9,826.2	9,970.3	1.79%	3.25%	3.44%	4.00%	5.53%
2005	9,598.6	10,127.5	10,296.9	1.60%	3.07%	3.28%	5.51%	7.27%
2006	9,390.2	9,997.4	10,214.1	-2.17%	-1.28%	-0.80%	6.47%	8.77%

2. General Approach

In reviewing the CMP sales forecast, we have considered various approaches to determining whether the forecast is reasonable. The first possible approach is the use of a simple trend projection derived from actual CMP sales growth realized in the past few years. The second possibility is to directly use regression equations without incorporation of end use data for residential customers, without interview data for commercial and industrial customers, and without direct industry by industry growth rates provided by DRI. We refer to this method as an econometric approach. The third possibility is to make adjustments to CMP's method by changing assumptions with respect to price forecasts, price elasticity factors, projections of economic conditions, appliance usage, interview data and DSM subtractions.

A trend forecast, the first alternative, has advantages because the method is simple and objective. The sales forecast approach developed by Bangor Hydro is essentially a trend forecast that does not account for projected information with respect changes in prices, economic conditions and appliance efficiency. A trend forecast, however does not consider information on how projected prices, projected changes in economic conditions and projected changes in the efficiency of electricity appliances affect electricity usage. Given recent events, including uncertain economic conditions, and significant changes in the price of energy, it is reasonable to expect that CMP sales in the rate affected period will not track the recent past. Therefore, in the case of CMP, we believe that the Commission should not use a simple trend approach. In other words, we believe in this case that the ability to forecast prices, income,

appliance efficiency and other factors does add information above a simple trend forecast.

CMP does not use a pure econometric approach. For example, the price elasticity for commercial customers is derived from a regression equation, but that equation is not directly used to forecast sales. Similarly, for the residential class, parameters from regression analysis are inserted to appliance usage forecasts. Econometric forecasts, in contrast to the CMP method, are made directly from regression equations whereby the sales forecast is forecast computed from a single mathematical equation that incorporates the price and income elasticity parameters.

CMP's forecasting approach uses features of the other methods and also includes customer specific forecasts from interviews. The price elasticity factors are added as a separate adjustments on top of base forecasts that incorporate appliance efficiency changes and industry by industry growth assumptions. The Bench Analysis described below uses CMP's forecast structure and makes various adjustments within that framework. For example, we adjust the price of electricity projections; we review price elasticity factors from CMP's regression equations and other sources; we consider the appliance forecasts; and, we examine CMP's interview process. The Commission has reviewed CMP's sales forecast in the past and CMP has devoted significant resources to its approach. We do not believe it would not be reasonable to use an entirely different approach in the context of this case.

3. <u>Actual Results Compared to Prior Forecast</u>

Before presenting detailed adjustments to CMP's sales forecast, we review general issues associated with CMP's sales forecast to provide background for

our analysis. In this section, we compare CMP's sales that were projected in Docket No. 97-580 to actual sales that have occurred in 2000 and 2001. We also compare CMP's sales forecast to other electricity sales forecasts. The background analysis demonstrates that CMP's approach produced estimates below actual realized levels and that its forecast is below other forecasts.

The table below confirms that CMP's actual sales have been significantly higher than the sales it forecast in Docket 97-580. Overall sales have been more than 6% above projected levels, and the variance between actual and projected sales occurred for each customer class.

Actual versus Forecast Sales, January 2000-September 2001	
Residential	5.10%
Commercial	3.90%
Industrial	8.80%
Total	6.10%

In evaluating CMP's previous forecast, we have attempted to consider factors that were used to derive the forecast as well as the final results of the forecasts. The variance between forecast and actual sales is in part explained by assumptions with respect to economic activity -- economic growth has been three to four percent above the forecast in the last case. However, electricity prices have been higher than amounts projected in the last case which should result in lower sales. A significant component of the variation for the industrial class is related to the assumption of cogeneration at International Paper that did not occur.

We have reviewed components of CMP's previous residential forecast as compared to actual sales in terms of the appliance by appliance usage and in terms of the number of new customers. **(Designated Confidential Information – Protective Order No. 4)**

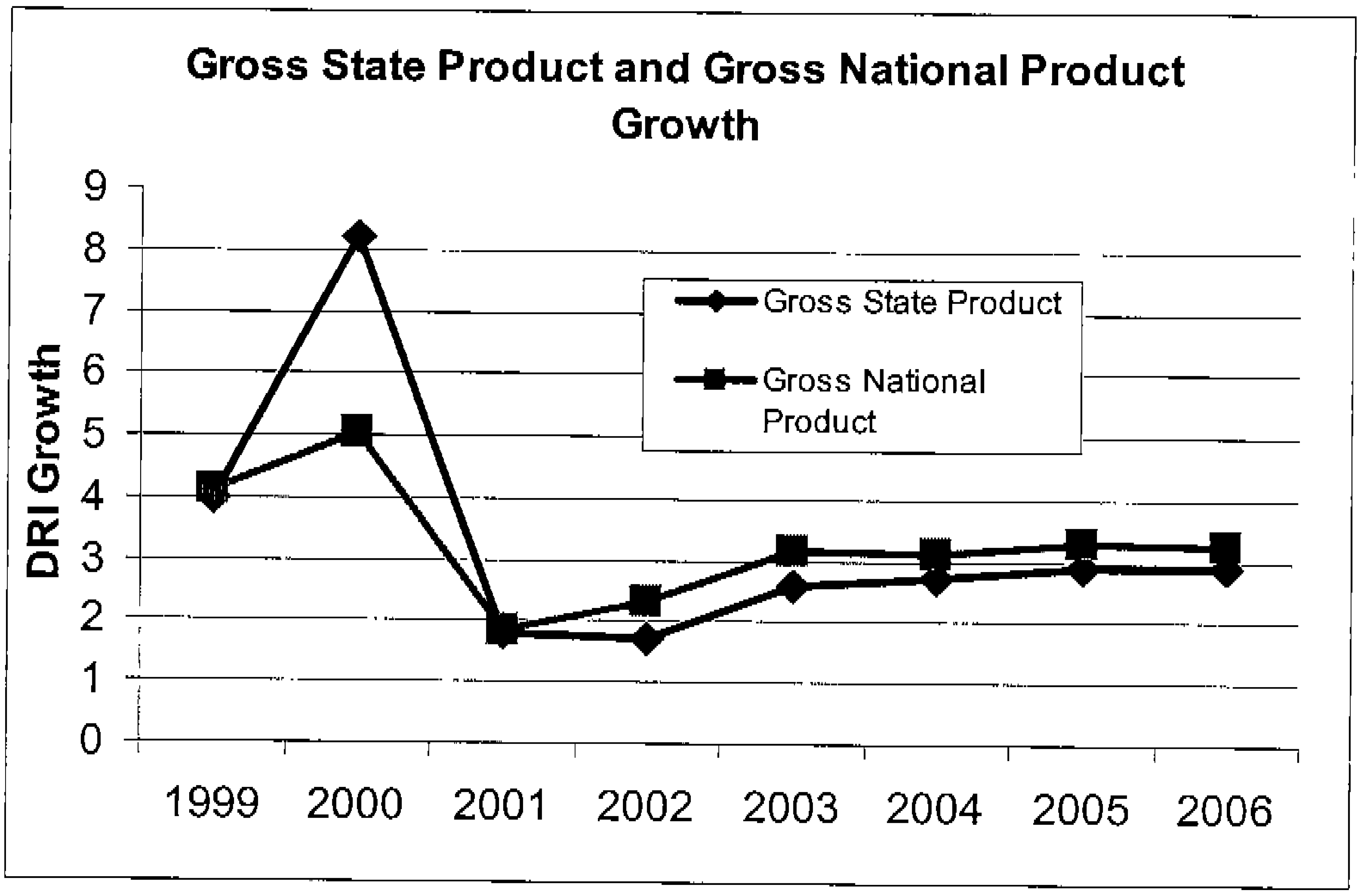
(Designated Confidential Information – Protective Order No. 4)

(End of Confidential information)

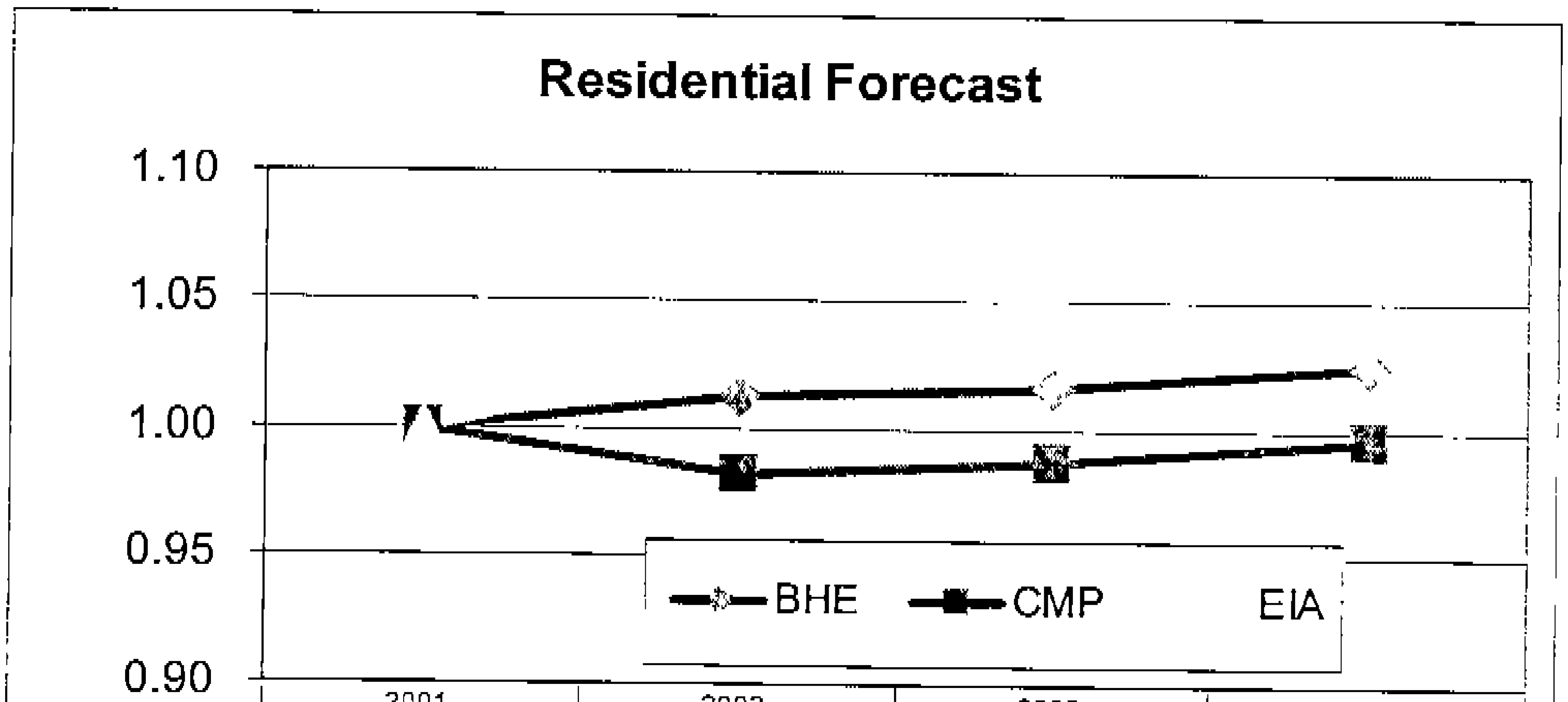
4. CMP's Sales Forecast Compared to Other Projections

We have compared CMP's forecast to other electricity energy usage forecasts as part of our general review of CMP's analysis. The forecasts we have reviewed include energy output projected in the Nepool Capacity, Energy, Load and Transmission report ("CELT") and projections of nationwide sales made by the Energy Information Agency ("EIA"). In addition, we compare projections made by CMP with forecasts made by Bangor Hydro.

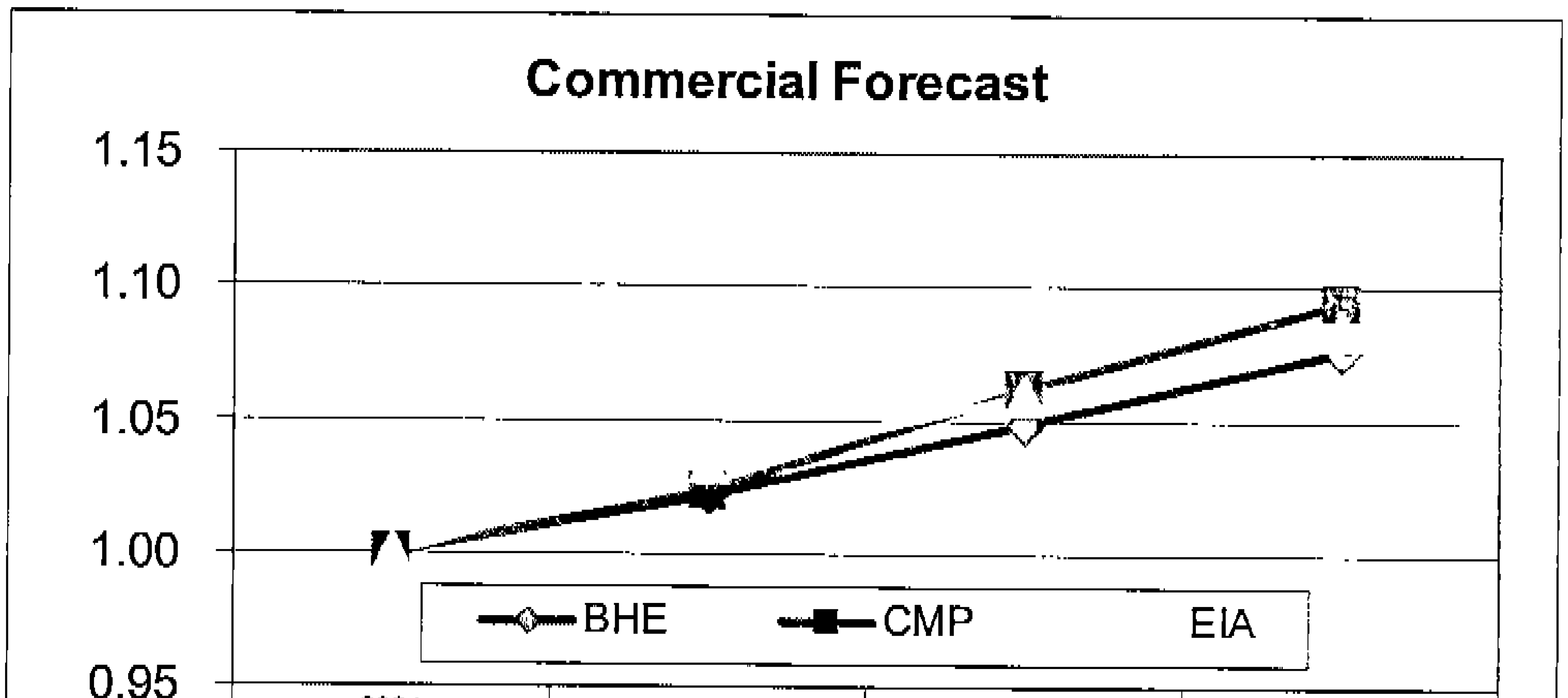
To provide context in comparing forecasts, we compare national growth with growth projected for the State of Maine. We acknowledge that CMP and BHE have unique service territory characteristics which should result in different forecasts than other nationwide or region-wide forecasts. However, some components of the other forecasts such as changes in appliance efficiency and general trends in energy prices should be common to all of the forecasts. The graph below demonstrates that while the forecast for the Maine economy is below the forecast for the national economy, the difference in growth is not sufficient to produce a significant electricity sales forecast difference.



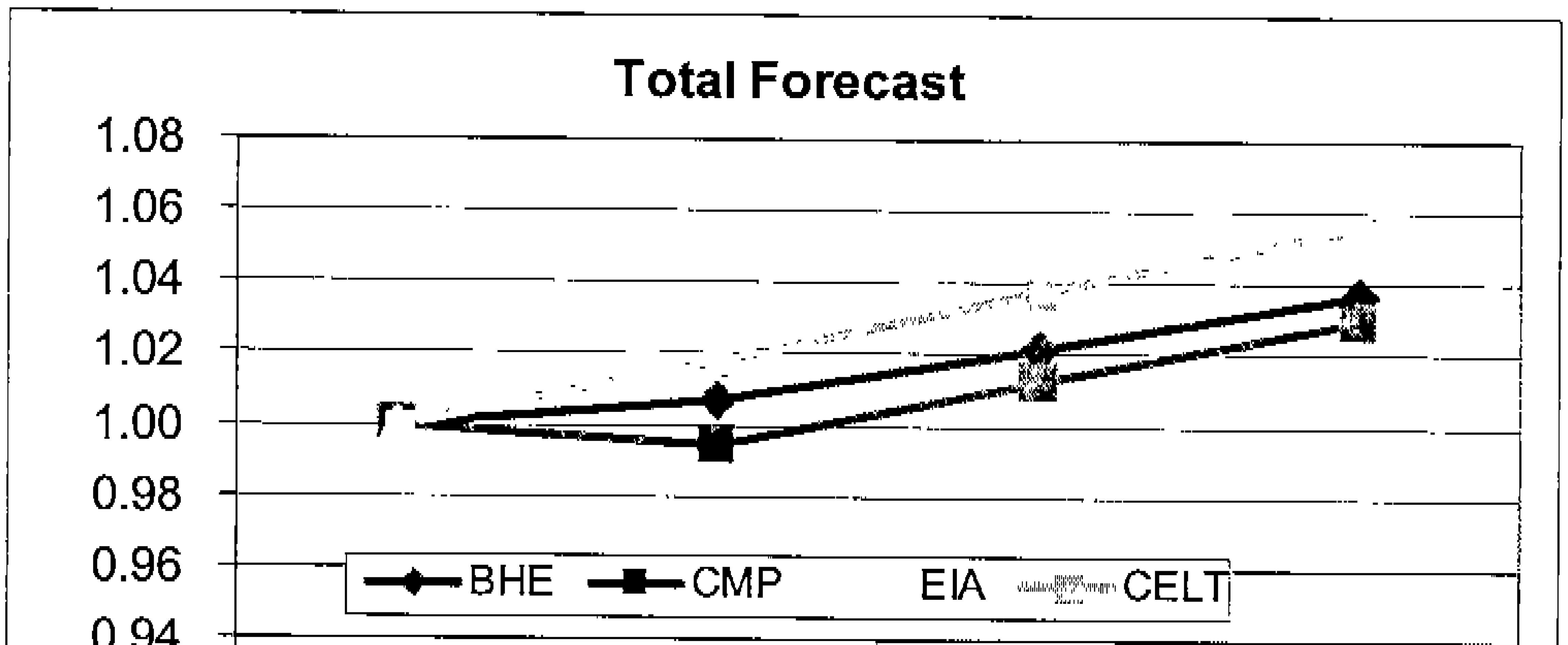
The graphs below shows that CMP's forecast for residential customers is below the forecast of BHE and EIA. The CELT forecast does not distinguish between residential, commercial and industrial customers. CMP forecasts for the commercial class are comparable to other forecasts. In terms of total sales, CMP's forecast is significantly below all of the other projections.



	2001	2002	2003	2004
BHE	1.00	1.01	1.02	1.02
CMP	1.00	0.98	0.99	1.00
EIA	1.00	1.03	1.05	1.08



	2001	2002	2003	2004
BHE	1.00	1.02	1.05	1.08
CMP	1.00	1.02	1.06	1.09
EIA	1.00	1.03	1.06	1.08



	2001	2002	2003	2004
BHE	1.00	1.01	1.02	1.04
CMP	1.00	0.99	1.01	1.03
EIA	1.00	1.03	1.05	1.07
CELT	1.00	1.02	1.04	1.06

B. Adjustments to Projected Prices for Quantification of Price Elasticity Impacts

In the next sections, we describe adjustments we have made to CMP's forecast. In this section we discuss adjustments to the price of electricity. In subsequent sections we describe adjustments to price elasticity factors, projected economic conditions, appliance efficiency, customer interviews, and DSM.

1. Method for adjusting prices

Projected future electricity prices affect the CMP sales forecasts through application of price elasticity. The lower the level of future prices, the higher the projected level of sales. For example, if the prices decline by 10% and the price elasticity is -.2, projected sales increase by 2%. This price elasticity adjustment arises from the formula for price elasticity in which elasticity is equal to the percent change in sales divided by the percent change in quantity. Multiplying the percent change in prices by the elasticity factor yields the percent change in quantity.

The Bench Analysis adjusts transmission, distribution, stranded investment and supply projected prices provided by CMP on a month-by-month basis. We have made various adjustments to the projected prices using the actual standard offer results for residential customers, alternative transmission and distribution price outlooks and adjustments to calculations of the stranded cost rate component. After making the adjustment to projected prices in nominal dollars, we have used CMP's projected inflation rates to compute the prices in real terms. The adjustments to the various components of prices are described below:

2. Transmission

CMP assumes a 10% increase in non-congestion revenue requirement that translates into a 10% per year price increase. After congestion costs are included, CMP's projected nominal price increase ranged from 8.5% to 8.8%. We have escalated the non-congestion transmission at a rate of 3% above inflation in 2002. For subsequent years we have assumed the transmission price increases at an

assumed annual inflation rate of 2.1% per year. We have reduced congestion costs to zero after June1, 2003. In 2002, the congestion costs are held constant at $8.9 million.

3. Distribution

CMP projects a nominal price decline of 2.97% in 2002 and 7.94% in 2003 for distribution. We have made adjustments to the CMP distribution rate changes to account for the estimated inflation, the productivity off-set and flow-through items. This produces a somewhat higher rate of decline in distribution costs in comparison to CMP's assumption.

4. Stranded Cost

We have used the stranded cost rate provided by CMP as updated for the proxy price for the QF entitlement sale for residential customers. We further reduced the stranded cost rate for residential customers to reflect higher estimated sales growth and a reduction of 2.5% due to revenue requirement adjustments. We compute the stranded cost rate on a revenue per kWh basis from CMP's exhibits in the case of commercial customers. The stranded cost rate for commercial customers is then reduced for revenue requirement and sales growth adjustments as discussed above for residential customers. For industrial customers, stranded investment charges are initially held at 2001 levels and then are adjusted for the same factors that are used to adjust residential and commercial rates.

5. Supply Price

For residential customers, we have adjusted supply prices to reflect actual standard offer prices for the period. For commercial and industrial customers, we have revised the supply prices assumed by CMP to reflect recent forward price data as

reported by NatSource. This analysis results in lower prices for the ICAP and for off-peak power. The prices for on-peak power are somewhat lower in years other than 2003.

We have not adjusted the bidder premium, losses, ancillary services and other factors from the CMP estimates.

CMP Assumptions						
Prices:	2001	2002	2003	2004	2005	2006
On Peak (/mWh)	$ 41.46	$ 44.00	$ 40.75	$ 40.00	$ 40.80	$ 41.62
Off Peak (/mWh)	$ 33.10	$ 33.00	$ 30.56	$ 30.00	$ 30.60	$ 31.21
ICAP (/mW)	$ 1.90	$ 1.90	$ 1.90	$ 1.90	$ 1.90	$ 1.90
Adders (/mWh) (3%/yr	$ 1.40	$ 1.44	$ 1.49	$ 1.53	$ 1.58	$ 1.62

Nat Source						
Prices:	2001	2002	2003	2004	2005	2006
On Peak (/mWh)	$ 41.46	$ 43.63	$ 42.00	$ 39.00	$ 39.78	$ 40.58
Off Peak (/mWh)	$ 33.10	$ 29.25	$ 28.16	$ 26.15	$ 26.67	$ 27.21
ICAP (/mW)	$ 1.90	$ 1.30	$ 1.10	$ 1.10	$ 1.10	$ 1.10
Adders (/mWh) (3%/\	$ 1.40	$ 1.44	$ 1.49	$ 1.53	$ 1.58	$ 1.62

6. Projected Retail Prices

The first three tables in the Bench Analysis Appendix show the final retail prices that result from the adjustments discussed above. The prices in these tables are stated in real terms consistent with the prices used in the price elasticity adjustments. We also present the four year moving average of real prices. We include the moving average prices in the analysis because long-run price elasticity is dependent on the changes in long-run prices rather than the current price level.

C. Adjustments to Price Elasticity Factors

1. CMP Method

As part of its sales forecast, CMP developed regression equations to estimate price elasticity for the three customer classes. For the residential class, CMP also uses the regression equation to estimate income elasticity. In the case of the commercial and industrial class, the regression equation that incorporates measures of income is only used to compute price elasticity for the forecast. CMP's regression equations develop short-run price elasticities. CMP could have, but did not attempt to compute long-run price elasticity in the regression equations by regressing sales against moving average prices or a series of lagged prices. In CMP's analysis, each regression (the residential, commercial, and industrial) has a different time period and the residential equation uses a lag of one year while the commercial and industrial equations do not have a lag.

2. Review of CMP's Regression Method

We have reviewed CMP's price elasticity estimates from two perspectives. First, we evaluated the regression equations using different specifications and the incorporation of long-run price elasticity. Second, we compare the CMP regression equation to other published studies. In analyzing the CMP regression analysis using data provided by the Company, we note several conceptual problems in developing the estimates. For the residential equation, the equation does not include the effect of appliance efficiency, the effect of long-run price response, the effect of heating degree days and other factors. The commercial regression equation does not account for changes in the industry make-up that has occurred in the past. In other

words, the price elasticity parameter could be distorted by changing industry make-up in the CMP service territory. The industrial regression equation does not "carve-out" the customers for which interviews were used and it also does not account for the changing make-up of industry in the service territory.

Given that the CMP regression equations are only are used for price elasticity, we have reviewed price elasticity parameters from other sources. Finally, we note that unlike CMP, Bangor Hydro uses a moving average price of eight quarters for commercial and industrial customers and a moving average of twelve quarters for residential prices in developing its regression analysis.

3. Comparison of CMP to Other Studies

The CMP estimates as compared to other price elasticity studies are compared in the table below. **(Designated Confidential Information – Protective Order No. 4)**

(End of Confidential Information)

D. Adjustments for Revised Economic Projections

1. CMP Method

CMP uses estimates of economic activity in its residential, commercial and industrial forecasts. In the residential equation, CMP projects personal income per household. In the commercial and industrial equation, CMP uses estimates of projected output on an industry by industry basis. The projections are based on a DRI study that was prepared before the terrorist attacks of September 11. CMP used Maine statewide estimates for each of the economic indicators rather than projections for specific CMP counties that represent its service territory.

2. Recent Forecast Updates

In response to a data request, CMP provided forecasts prepared by NEEP that have been made subsequent to the tragedy. The Bench Analysis uses differences in the Gross State Product ("GSP") projected by the recent NEEP forecast relative to the previous NEEP forecast and adjusts personal income and growth rates of various industries. The difference between NEEP forecast prepared before the September 11 and after September 11 in terms of the Maine GSP is illustrated in the graph below.

(Designated Confidential Information – Protective Order No. 2)

(End of Confidential Information)

The relative difference in GSP is applied to output growth rates on an industry by industry basis for purposes of the commercial and industrial forecast. In the case of the residential forecast, the NEEP forecasts of Maine personal income are directly used rather than the GSP change. The results of applying the NEEP forecast differences to the factors that drive the CMP forecasts is illustrated in Tables 4 through 6 of the Bench Analysis Appendix. The tables illustrate growth rates before and after adjustments for the recent NEEP forecast for each customer class.

E. CMP Service Territory versus Statewide Growth

CMP's forecasts are based upon Maine statewide economic estimates rather than the counties that represent the CMP service territory. The graphs below show that in terms of personal income growth used in the residential forecast and manufacturing employment growth used a proxy for the commercial and industrial growth, the growth in CMP counties has been and is expected to be greater than statewide growth. The Bench Analysis increases personal income growth in the residential forecast by .15% percent per year, and it increases industry growth rates by .1% per year in the commercial and industrial forecast.

(Designated Confidential Information – Protective Order No. 2)

(End of Confidential Information)

F. Adjustments to Appliance Use in Residential Forecast

(Designated Confidential Information – Protective Order No. 4)

(End of Confidential Information)

8. Number of Customers

We have reviewed CMP's forecast of the number of residential customers applied to the residential use per customer. While CMP under estimated the number of customers in the prior case, the method results in approximately the same

customer increases as housing starts consistent with history. Therefore, we have not made an adjustment to the projected number of new customers. Graphs demonstrating our analysis of the number of new customers is illustrated in the Bench Analysis Appendix.

G. Customer Interviews

1. Summary

CMP uses customer interviews in its projections of sales to commercial customers, other industrial customers and pulp and paper companies. We agree that the customer specific forecasts may possibly provide information not available from other sources such as DRI. However, we believe the customer specific data may lead to a systematic under-estimation of sales. In reviewing the customer interview data, we discuss mechanics of making the forecasts with and without interview data; we consider theoretical arguments for using customer interviews; and we evaluate the historic efficacy of customer interviews. As described above, the commercial and industrial forecasts are made with and without the customer interview data.

(Designated Confidential Information – Protective Order Nos. 2 & 4)

(End of Confidential Information)

2. Mechanics of Removing Customer Interview Data

In making the commercial and industrial forecasts, CMP either uses an industry growth rate provided by DRI or interview data. If the customer interview data is zero in CMP's spreadsheets, the industry output adjusted for price elasticity is applied as the default in the forecast. Because of these mechanics, price elasticity is only incorporated in the non-interview projections. If the interview data is not used, then the DRI projected industry growth rates for the commercial class are directly used. In other words if industry output is projected to grow by 2%, electricity sales are also

projected to grow by 2%. In the industrial class, the industry by industry output growth is reduced in computing electricity growth by multiplying the growth rate by a factor of .69. (We have evaluated CMP's use of the .69 factor in the industrial class which suggests that manufacturing output can be produced with less and less electricity. The historic data confirms CMP's assumptions.)

In making projections without customer interviews, we simply insert zero into the customer interview data in CMP's spreadsheets. This causes the industry output growth rates and price elasticity to be used by default. In the case of pulp and paper companies, we could not make this sort of adjustment. Therefore, for the pulp and paper industry, the Bench Analysis does not include scenarios with and without interview data because alternative information on price elasticity and future economic conditions does not exist.

3. Theoretical Issues

As economic activity occurs, some customers will fall off the system and some new customers will be added to the customer base. Furthermore, existing production capacity in CMP's service area does not decline if a company declares bankruptcy or even moves out of the area. Therefore, if only customer losses are included in a sales forecast, the analysis will be inherently biased downwards. A specific example of this is Maine Poly where CMP projected zero sales because of the bankruptcy of the company. However, we understand that new owners will take over the facility and begin operations in 2002 using the capacity of this plastics plant.

Bangor Hydro recognized the notion that only assuming customer exits without assuming new customers in a forecast will lead to a downward bias. To

correct for this fact, in its forecast, BHE added a "mysterious" new customer in its analysis. Finally, the interview process itself may lead to circumstances where employees of customers simply project future use at current levels and they do not have an incentive to devote significant resources to making a forecast.

4. Past Performance of Customer Interviews

In assessing the question of whether customer interview data should be used in the CMP sales forecast, we have attempted to compare projected sales from interviews conducted in Docket No. 97-580 with actual sales on a customer by customer basis. The interview forecast was presented in April, 1999. This means that when comparing results for 1999, the interview process should already incorporate some actual data.

The comparison of actual versus forecast for pulp and paper industry customers is shown below. **(Designated Confidential Information – Protective Order No. 1)**

(End of Confidential Information)

For the commercial class, the analysis was more difficult because of limited customer overlap between customer by customer interviews in this case as compared to the last case.

H. Demand Side Management Adjustments

After developing forecasts from customer interviews, appliance data, economic conditions and price elasticity, CMP reduces sales levels for DSM savings. The DSM savings are projected to arise from programs developed by the State

Planning Office ("SPO"). In considering the DSM adjustments, we have concerns related to two issues. The first issue involves whether CMP may be double-counting DSM savings in its customer forecasts. The second issue is whether the DSM savings that CMP projects to arise from SPO programs will in fact be realized. Because of questions raised by both issues, the Bench Analysis reduces DSM savings by half relative to CMP's projections.

Potential double counting issues associated with DSM exist for each customer class. For residential customers, the appliance efficiency and the appliance saturation for water heat and lighting should reflect savings associated with historic CMP programs. If DSM is eliminated, one would expect the lighting and water heat sales to increase relative to historic levels. In other words, if DSM is continued at historic levels, the historic trends should continue ***without*** any separate adjustment for DSM. Similarly, in computing the income elasticity, the regression coefficient is developed from data after the presence of DSM programs. If DSM were added back to sales as in the Bangor Hydro forecasts, the estimated income elasticity would be different. With a higher income elasticity, the sales levels would be greater suggesting that DSM should not be separately adjusted in the residential class.

In the case of commercial and industrial customers, the double counting issue involves whether DSM is included in the interview process and whether DSM is incorporated in the .69 factor CMP uses to convert manufacturing output to electricity sales. The interview process supposedly reflects electricity sales after all DSM activities including projected savings from programs developed by the SPO. If the sales are already reduced for DSM, separate DSM subtractions should not be made. Further if

the .69 factor is estimated from data after DSM activities, that parameter already reflects DSM and further subtractions should not be made.

Aside from double-counting, a separate issue involves the level of CMP's projected DSM savings from SPO programs. In addition to questions involving commercial and residential programs, to the extend that DSM is targeted to customers that will become cogeneration customers, the base of the energy usage has already been taken out of the CMP forecast. Given all of the conceptual and realization problems with DSM, the Bench Analysis reduces projected DSM savings in the sales forecast by fifty percent and requests that CMP address the issues of the DSM double-count and the feasibility of its projections in its reply to the Bench Analysis.

I. Pulp and Paper Industry Forecast

(Designated Confidential Information – Protective Order No. 1)

(End of Confidential Information)

J. Results by Class

The tables below illustrate components of the adjustments we have made to the residential, commercial, industrial and pulp and paper forecast. In each table, we begin with CMP's forecast and then separately show how the forecasts change due to different forecasts of the price of electricity, different price elasticity factors, different forecasts of economic conditions, different forecast results from focusing on growth in CMP's service territory rather than statewide growth and different DSM adjustments.

The residential forecast also includes different assumptions with respect to appliance use for miscellaneous uses, refrigerators, and space heat. In the case of forecasts for commercial and industrial customers, two revised forecasts are presented with and without including results from CMP's customer interviews.

	Commercial Sales - Sales Forecast with Interviews						
	2000	2001	2002	2003	2004	2005	2006
CMP Presentation	2,813.2	2,900.0	2,964.9	3,078.3	3,172.7	3,251.6	3,333.8
Adjustment to Price of Electricity	2,813.2	2,899.9	2,970.0	3,089.0	3,191.7	3,276.4	3,360.8
Price Elasticity Adjustment and Price Adjustment	2,813.2	2,839.7	2,945.8	3,109.6	3,256.1	3,397.4	3,493.6
Above Adjustments with Current NEEP Forecast	2,813.2	2,833.2	2,880.5	3,055.5	3,189.1	3,326.7	3,420.3
Above Adjustments with CMP versus Maine Adjustment	2,813.2	2,834.1	2,883.8	3,061.7	3,198.3	3,339.3	3,436.5
Above Adjustments with Lower DSM	2,813.2	2,834.1	2,895.8	3,080.7	3,224.4	3,372.5	3,476.7
	Commercial Sales with Interviews - Percent vs CMP						
CMP Presentation							
Adjustment to Price of Electricity	0.00%	0.00%	0.17%	0.35%	0.60%	0.76%	0.81%
Price Elasticity Adjustment and Price Adjustment	0.00%	-2.08%	-0.65%	1.02%	2.63%	4.49%	4.79%
Above Adjustments with Current NEEP Forecast	0.00%	-2.30%	-2.85%	-0.74%	0.52%	2.31%	2.59%
Above Adjustments with CMP versus Maine Adjustment	0.00%	-2.27%	-2.74%	-0.54%	0.81%	2.70%	3.08%
Above Adjustments with Lower DSM	0.00%	-2.27%	-2.33%	0.08%	1.63%	3.72%	4.29%

	Commercial Sales - Sales Forecast without Interviews						
	2000	2001	2002	2003	2004	2005	2006
CMP Presentation	2,813.2	2,900.0	2,964.9	3,078.3	3,172.7	3,251.6	3,333.8
CMP Assumptions: No Interviews	2,813.2	2,900.6	2,984.3	3,111.4	3,218.5	3,313.0	3,406.3
Adjustment to Price of Electricity	2,813.2	2,900.6	2,990.4	3,124.5	3,241.7	3,343.3	3,439.3
Price Elasticity Adjustment and Price Adjustment	2,813.2	2,826.7	2,960.8	3,149.7	3,320.5	3,491.3	3,601.6
Above Adjustments with Current NEEP Forecast	2,813.2	2,818.7	2,860.9	3,082.3	3,238.1	3,404.3	3,511.5
Above Adjustments with CMP versus Maine Adjustment	2,813.2	2,819.9	2,884.9	3,089.6	3,249.0	3,419.2	3,530.4
Above Adjustments with Lower DSM	2,813.2	2,819.9	2,896.9	3,108.7	3,275.1	3,452.3	3,570.6
	Commercial Sales - Percent vs CMP						
CMP Presentation							
CMP Assumptions: No Interviews	0.00%	0.02%	0.65%	1.08%	1.44%	1.89%	2.17%
Adjustment to Price of Electricity	0.00%	0.02%	0.86%	1.50%	2.17%	2.82%	3.16%
Price Elasticity Adjustment and Price Adjustment	0.00%	-2.53%	-0.14%	2.32%	4.66%	7.37%	8.03%
Above Adjustments with Current NEEP Forecast	0.00%	-2.80%	-2.84%	0.13%	2.06%	4.70%	5.33%
Above Adjustments with CMP versus Maine Adjustment	0.00%	-2.76%	-2.70%	0.37%	2.40%	5.15%	5.90%
Above Adjustments with Lower DSM	0.00%	-2.76%	-2.30%	0.99%	3.23%	6.17%	7.10%

Other Industrial Sales - Sales Forecast with Interviews	2000	2001	2002	2003	2004	2005	2006
CMP Presentation	1,639.3	1,557.5	1,558.0	1,604.4	1,647.1	1,695.1	1,722.2
Adjustment to Price of Electricity	1,639.3	1,557.5	1,561.6	1,608.4	1,652.4	1,701.1	1,728.7
Price Elasticity Adjustment and Price Adjustment	1,639.3	1,557.5	1,571.6	1,631.4	1,687.1	1,740.0	1,766.9
Above Adjustments with Current NEEP Forecast	1,639.3	1,557.4	1,562.9	1,624.4	1,678.6	1,731.2	1,757.9
Above Adjustments with CMP versus Maine Adjustment	1,639.3	1,557.4	1,563.5	1,625.4	1,680.2	1,733.4	1,760.8
Above Adjustments with Lower DSM	1,639.3	1,557.4	1,562.8	1,624.1	1,678.3	1,730.8	1,757.6

Other Industrial Sales - Percent vs CMP with Interviews							
CMP Presentation							
Adjustment to Price of Electricity	0.00%	0.00%	0.23%	0.25%	0.32%	0.35%	0.38%
Price Elasticity Adjustment and Price Adjustment	0.00%	0.00%	0.87%	1.68%	2.43%	2.64%	2.60%
Above Adjustments with Current NEEP Forecast	0.00%	-0.01%	0.32%	1.24%	1.91%	2.13%	2.08%
Above Adjustments with CMP versus Maine Adjustment	0.00%	0.00%	0.35%	1.31%	2.01%	2.26%	2.24%
Above Adjustments with Lower DSM	0.00%	0.00%	0.31%	1.23%	1.89%	2.11%	2.05%

Paper Forecast	2000	2001	2002	2003	2004	2005	2006
CMP Presentation	1,993.9	1,620.0	1,578.1	1,578.9	1,579.7	1,580.5	1,231.4
Adjustment for Lost Contract	1,993.9	1,620.0	1,601.1	1,601.9	1,602.7	1,603.6	1,254.4
Other Adjustments from Trends	1,993.9	1,629.6	1,611.8	1,612.0	1,612.2	1,612.4	1,262.6

Paper - Percent vs CMP							
CMP Presentation							
Adjustment for Lost Contract	0.00%	0.00%	1.46%	1.46%	1.46%	1.46%	1.87%
Other Adjustments from Trends	0.00%	0.59%	2.14%	2.10%	2.06%	2.02%	2.54%

IV. STRANDED COST PROJECTIONS

A. Impact of the 8 Mill Mitigation on the Asset Sale Gain Account Balance

In our Phase I Bench Analysis, we recommended that the impact of the Commission's decision this past spring in Docket No. 97-580 to mitigate the impact of increases in the price of supply by decreasing stranded rates for certain customer classes by accelerating the amortization of the Asset Sale Gain Account be based on the billing units used to establish rates in that proceeding. In its Phase II filing, the Company argued that the approach proposed by the Advisory Staff would not make the Company whole and that the amount to be credited against the ASGA should be based on actual billing units. Based on the Company's responses to discovery it now appears that there is no material difference between these two approaches. While the Advisory Staff continues to believe that its approach is theoretically correct, given the inconsequential difference on revenue requirements between the two approaches, no further discussion is warranted at this time.

B. Cost Deferrals

1. RWS Contract Buyout

CMP and Regional Waste Systems, Inc. (RWS) were parties to PPA under which RWS generated and sold power to CMP for a 20-year period from 1988 through 2008. RWS is a quasi-municipal organization made up of member municipalities in Cumberland and York counties organized to develop, own and operate a waste-to-energy facility as a means to dispose of municipal solid waste. The waste-to-energy facility is a qualifying facility (QF) under PURPA. The PPA had a two-part formula to determine how much CMP paid RWS for electricity RWS generated. For the

first 13 years (through 2000), the PPA defined a specific rate. For the last seven years, beginning January 1, 2001, the PPA used a percentage of the "standard long-term avoided costs rates established by the Commission for the third 50 megawatt decrement."

RWS sued CMP in 1998 in order to establish the appropriate basis for the PPA rates beginning January 1, 2001. It was CMP's position that the entitlement sale prices, established through the Chapter 307 auction process, were the appropriate avoided costs. RWS's position was that the appropriate avoided costs were the decrement 87-A avoided costs approved in Docket 87-261. If RWS prevailed in litigation, CMP would have paid RWS about $25 million more to RWS over the eight years. The present value of that difference on January 1, 2001 was more than $17 million.

On February 14, 2000, CMP entered into an agreement with RWS in which CMP would pay RWS $3.8 million and the RWS PPA would be terminated on December 31, 2000. By the terms of CMP's Chapter 307 agreement with Engage Energy, CMP was required to replace the energy and capacity from the RWS PPA or obtain Engage's consent not to do so. As Engage did not consent, CMP had to reach agreement with Engage on replacing the capacity and energy to RWS.

On September 27, 2001, the Advisors conducted a technical conference on the RWS buyout. Through the conference and data responses, we have reviewed the PPA, the pleadings from the litigation and privileged analysis by CMP's attorneys. Based upon this review, we preliminarily conclude that CMP acted reasonably to settle the litigation for a payment of $3.8 million. **(Designated**

Confidential Information – Protective Order No. 3)

(End of Confidential Information)

We also conclude that CMP acted reasonably in purchasing energy and capacity to replace the RWS RPA, even though the costs of replacement power is almost as large as the litigation settlement. For various reasons, CMP did not finalize arrangements with Engage until December 2000. While in retrospect, this was particularly bad timing in terms of energy prices, it was understandable that CMP took that long in reaching agreement with Engage, because of the beginning of retail access in Maine, the May 6, 2000 ISO-NE spot prices of $6000/MWh, and changes in Engage's organizational structure. Given the timing that CMP faced, the energy and capacity arrangements that CMP has made are consistent with market-based forward prices that we have reviewed.

2. Special Contracts

Under the special contract deferral mechanism provided for in the Docket No. 97-580 ("Mega-case") Stipulation, for categories (i) and (ii) contracts[1], CMP was allowed to defer the difference between the T&D prices:

> paid by customers under targeted rates and contracts and the transmission and distribution prices assumed to be paid by these customers for establishing rates in this proceeding consistent with the procedural and ratemaking decisions set forth in the June 22 Order on Reconsideration.

Stipulation at 15. At this time, CMP's estimate of this deferral amount is approximately $13.1 million. (Volume I, Exhibit Call/Dumais-3)

Our review of CMP's calculations is still continuing. We are reviewing both CMP's calculations underlying the deferral amount as well as the reasonableness of the contract rates in the deferral. While we have not completed this review, we have at this time identified at least one major area of concern. Specifically, we are concerned that the rates charged to the sub-transmission voltage level ski areas may have been lower than necessary to retain their load.[2] **(Designated Confidential Information – Protective Order No. 5)**

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[1]Category (i) contracts were described in the Stipulation as those contracts that were required to be unbundled, maintaining existing benefits and burdens (as required under 35-A M.R.S.A., § 3204(10)) and category (ii) contracts were described as those that were a renewal of an ARP arrangement (ARP comparable).

[2]We have identified only the rates charged to the sub-transmission ski areas as an issue because the amount of dollars associated with the smaller ski areas is not large and because the smaller areas have represented that their alternative is more likely to be a reduction in usage rather than installation of self-generation.

(End of Confidential Information) If CMP has additional information that supports its rate of 0.035 \$/kWh to these customers during the deferral period, however, we invite it to file such in its response to this Bench Analysis.

Another issue that we have examined is whether the deferral should include customers that were assumed in the Mega-case to have their contracts extended but actually took service under the core retail rate. There appear to be 4 such customers[3]. CMP did not include any amounts for these customers in the deferral. Including these amounts in the deferral would lower the deferral amount by approximately \$480,000. It could certainly be argued that these customers should have

[3]These customers are Brooks Textiles, George Flood, Maine Poly and Wright Place Farms.

been included in the deferral as rates were set in the Mega-case, assuming these customers would continue on special rates and be part of the deferral amount. The rates these four customers paid were no more certain at the time of the Mega-case than the rates of customers who received greater discounts than was expected, and to exclude the customers after they returned to core rates tends to increase the deferral in an asymmetric way (i.e. removing only customers that pay more rather than less than was assumed in the Mega-case). However, as we discuss further in the BHE stranded cost proceeding (Docket No. 2001-239), a strict reading of the language in the stipulations supports excluding such amounts from the deferral calculation. Therefore, we are not recommending any adjustment associated with this issue.

C. Revenue from Non-Core Customers

Our review of CMP's calculations of future non-core revenue is still continuing. While we have not completed this review, at this time we have identified several areas of concern.

As described in the August 16, 2001 Bench Analysis, CMP's method generally assumes that non-core customers pay retail rates for transmission and distribution, thereby attributing the full discount to a loss in stranded cost revenue. We continue to be concerned that this shifts the risk of discounts from shareholders to ratepayers. Thus it is important to note that while CMP's approach is consistent with how distribution rates were set in ARP 2000, such a shift is completely reverse to what was anticipated when the Commission approved the broad discretion afforded CMP under its flexible pricing provisions of the ARP. This highlights the need for some type

of stranded cost incentive rate plan which actually incorporates the Commission's flexible pricing goals.

We are also continuing to review CMP's assumptions regarding the level of rates expected from the non-core customers in the 3-year rate effective period. Specifically, we are concerned with CMP's assumption that current T&D contract rates would continue to be offered even though electricity supply prices have fallen. Many of the contracts currently in effect were negotiated at a time when market electricity supply prices were significantly higher than they are today. Because the supply price is subtracted from the cost of the alternative to determine the minimum T&D rate that a non-core customer should pay, a reduction in supply prices may allow an increase in the T&D prices CMP can charge to non-core customers.

CMP has suggested that no adjustment is necessary because when market prices change, the cost of the alternative also changes. We agree that factors that cause changes in the market price of generation also tend to change the cost of customers' self-generation alternatives. However, CMP did not do any analysis to better define this relationship. We are concerned that changes in the market price of generation may not have a direct $/kWh correlation to changes in the cost of the customers' alternatives for several reasons.

While the generation market may track changes in fuel prices, it is not clear that this represents a one-to-one relationship. For example, a 10% decrease in the forward price of diesel fuel may not cause exactly a 10% decrease in the generation market price. Moreover, even if it did, customer's alternatives often include some fixed costs in addition to fuel costs. Therefore, percentage changes in fuel cost may have a

different effect on the T&D price than the same percentage change to the market generation price would.[4]

Second, to the extent that the discount was offered for economic development reasons, it is not clear that a reduction in generation price should translate directly to an increase in T&D price. Further, there is variation in the fuel efficiency of different alternatives. Therefore, a change that causes the fuel price for one customer's alternative to go down 2¢ per kWh, may cause another customer's alternative cost to go down by only 1¢ per kWh. Finally, customers sign generation contracts at different times and for different lengths of time. While CMP may not have information on the terms and timing of all customers' generation contracts, it may have information for some of them and it could request such information from others.

We are also concerned, for the reasons described in the deferral section, that the rates assumed to be charged to the sub-transmission voltage level ski areas may be lower than was necessary to retain their load. **(Designated Confidential Information – Protective Order No. 5)**

(End of Confidential Information) Without having reviewed the relationship between

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[4] For example, if a customer's alternative cost starts out as 3 ¢/kWh for fixed costs, 4 ¢/kWh for fuel costs (total alternative cost of 7¢/kWh) and a generation price of 5¢/kWh, their starting T&D price would be 2¢/kWh. If both fuel and generation decreased by 10%, however, the new total price for the alternative would be 6.6 ¢/kWh (3¢/kWh plus 3.6¢/kWh) and the new price for generation would be 4.5¢/kWh, producing a new T&D price of 2.1¢/kWh, not 2.0 ¢/kWh.

expected changes in the cost of the ski areas' alternatives to expected changes in their cost of generation, we cannot know whether such an increase is reasonable. However, based on the information that we have, if CMP's assumption is correct that the relationship between alternative costs and market generation prices is reasonably static, such an adjustment may be warranted.

D. Stranded Costs from QF Contracts

As of March 1, 2002, CMP's portfolio of PPAs will include 30 agreements with Qualifying Facilities and three arrangements for system energy and capacity that resulted from the prior restructuring of agreements with QF projects.

1. Projected QF Deliveries and Costs

To estimate QF deliveries, CMP divides its QF contracts into four categories: hydro, thermal, system and STEO. For the 24 PPAs with hydro-electric projects, CMP estimates deliveries based on the historical average of actual deliveries during the five-year period ending December 31, 2000. CMP used a five-year average in Docket No. 97-580 also (for the period ending on December 31, 1998).

For the six PPAs with thermal QF generating projects, CMP estimates delivery volumes using the historical average of actual deliveries during the three-year period ending December 31, 2000. Again, the methodology is identical to that used in Docket 97-580.

For the three system power agreements, the annual delivery projections are based on volumes specified in the individual agreements.

CMP estimates QF purchase power costs by multiplying the estimated deliveries by the applicable contract rate or rates. Contract rates are fixed,

tied to an inflation index, indexed to wholesale electric prices, tied to retail electric rates, based on long-term avoided costs or STEO (short-term energy only) rates. Certain of the PPAs also include fixed payments.

Contracts with rates tied to retail electric rates and long-term avoided costs are subject to disputes between CMP and the QFs. CMP suggests that differences between actual costs and estimates be deferred for later rate treatment.

2. Mega-Case Ratemaking

For the period March 1, 2000 through February 28, 2001, Mega-case estimates were $6 million higher than actual net costs for QFs that were not subject to deferral. CMP states that estimates were higher than actuals because of relatively low hydro conditions and Mead (Rumford Cogen) and Champion underproduction.

Mr. Stinneford and Mr. Hanson describe this experience as "somewhat outside the normal range of expected variances." They do not, however, believe that the QF cost methodology should be adjusted. The 5-year hydro average includes the low hydro year of 2000, and there is no better long-term weather production than historical period averages. The conditions resulting in the underproduction at Mead and Champion are resolved and not expected to recur. In addition, the 3-year average incorporates the 2000 under-production into the new estimate.

Looking at historical QF data, the Advisors do not believe that the 5-year period and 3-year averages proposed by CMP are inherently flawed or unfair. The Mega-case rate effective experience, however, does point out a shortcoming of the

ratemaking approach used in that case. The impact of a significant or long-term operations difficulty by a QF during the rate-effective period will not be adequately captured under a typical ratemaking approach. The Advisors support an idea that we believe was suggested by Mr. Call and Mr. Dumais at a recent technical conference. The suggestion was that CMP could defer the effect of an actual forced outage rate for any QF facility that is greater or less than the forced outage rate implicit in the QF cost estimates used to set rates in this proceeding.

3. Continued Effort to Mitigate QF Costs

CMP bought out two QF contracts in the last 2 years. Of the remaining 34 contracts, 25 have been previously restructured. Of the "never-been" restructured nine contracts, the vast majority of CMP purchases are from three large cogeneration facilities. CMP states that strategies and achievable benefits applicable to stand-alone facilities are not applicable to a cogeneration facility. CMP also states that it continues to seek restructuring possibilities despite this major impediment. In a confidential data response (ODR-01-04), CMP describes these efforts.

CMP's Power Contracts Administration Department administers the 34 active QF contracts. The department currently consists of a manager, two contract administrators, one contract analyst and a secretary. As restructuring opportunities are identified, resources from CMP's legal and financial analysis departments are devoted to their analysis and subsequent negotiations. This department also manages standard offer procurement and administration, a function that has required much greater use of utility resources than the Commission anticipated in the planning stages of restructuring.

In its Phase I Order in Docket 97-580, the Commission directed that 90% of any net QF contract restructuring savings be retained by CMP. In the ARP 2000 docket, the Advisors recommended an increase to CMP's portion to 25%, based upon a its belief that 10% may not be a sufficient corporate incentive.

The Advisors acknowledge that the power contracts administration unexpectedly has been required to devote significant resources to standard offer procurement. Moreover, we agree that this effort should be given a high priority by CMP as it has been essential to the Commission's effort to satisfy its statutory obligation of assuring reasonably priced standard offer service for Maine consumers. However, at this point, it is unclear to what extent the Commission will continue to need to rely on CMP to devote significant effort to standard offer matters.

At this point, the Advisors are not certain on the means to best provide for a QF incentive mechanism, or otherwise ensure that CMP reasonably mitigates QF stranded costs. It would appear, however, that prior to restructuring, CMP was able to allocate greater corporate resources to the buyout/buydown effort. Accepting CMP's description that the remaining contracts are more difficult to restructure, it may be that more rather than less corporate resources are necessary to accomplish additional stranded cost mitigation. It is not clear that merely increasing the percentage of savings retained by shareholders will have sufficient impact.

The Advisors suggest that, after CMP's future role in standard offer matters becomes clear, which should be within the next few months, CMP and Staff meet informally to discuss how to address this. If a satisfactory approach cannot be developed informally, the Advisors will then recommend a more formal approach.

E. Hydro-Quebec Tie-Line

CMP is a supporting participant in the high voltage direct transmission interconnection between New England and the Province of Quebec, Canada. CMP is not an owner of the Interconnection facilities, but is obligated to financially support approximately 7% of the Interconnection through several support agreements. These agreements obligate the supporting participants to proportionately compensate the Interconnection owners for the cost of constructing, owning and operating the Interconnection. CMP estimates that the 12-month support cost for each of the rate effective years will be $5.8 million, $5.6 million, and $5.4 million. These estimates are based upon projections received from the owners of the Interconnection facilities.

The Hydro-Quebec Firm Energy Contract (FEC) expired by its terms on August 31, 2001. Although CMP no longer has contractual rights to any power entitlements over the HQ tie line, it retains certain rights to the proportionate use of the tie-line and Interconnection facilities. In addition, NEPOOL voted to allocate the capacity tie benefits directly to the supporters of the HQ facilities beginning September 1, 2001. This vote has been appealed, but ISO-New England has implemented the decision pending appeal. Unless the appeal is successful, CMP will receive 45 mW of capacity in winter months and 127 mW in the non-winter months.

To determine stranded costs revenue requirement, CMP includes the forecasted support costs but does not include any capacity value or transmission revenue. CMP asserts that the NEPOOL appeal and uncertainty of how FERC will dispose of the HQ interconnection in the establishment of a New England or Northeast RTO make any estimate of value to be received too speculative. CMP proposes to

defer for future treatment any revenue or other benefits derived from the line. CMP also proposes to defer any recovery of costs that results because HQ costs are "socialized in a large RTO context".

The Advisors agree with the deferral proposed by CMP. However, since we expect some value to be obtained from CMP's transmission rights, we propose to include an estimate of that value in the revenue requirement calculation (e.g. based on forward prices for ICAP) and to defer any difference between the estimate and actual value received. Also, as to estimated support costs, we note the Interconnection facility owners have overestimated such costs each of the last 4 years. (See Ex-02-33 in Docket No. 01-239) The support costs used to determine stranded cost revenue requirement in this case should be adjusted downward by 5% to reflect the owner's historical overestimation of support costs.

F. Nuclear-Related Stranded Costs

1. Maine Yankee

a. NEIL Member Account Balance

Maine Yankee was a member of Nuclear Electric Insurance Limited (NEIL), a mutual insurance company[5] which provides insurance protection against property damage to the nuclear power facilities owned by its members. Maine Yankee purchased insurance from NEIL since at least 1982. Through September, 1999, Maine Yankee accounted for all payments to NEIL as an O&M expense. Each year, at least since 1989, NEIL would distribute money to its members in the nature of a

[5]NEIL was incorporated in 1980 under the laws of Bermuda and is a registered insurer under the Bermuda Insurance Act of 1978 and the Captive Insurance Companies Act of Delaware.

dividend, based on the prior year's premiums, claims and earnings experience. Earnings that were not distributed to members were apparently credited to Member Account Balances. Distributions received each year by Maine Yankee were credited against O&M expense in the year received by Maine Yankee. Thus, the distribution received in 1990, that was based upon NEIL's 1989 premiums, claims and earnings, was credited to 1990's O&M expense.

In January 1999, Maine Yankee received NRC exemptions permitting the Company to lower its insurance coverages to the point where no excess insurance needed to be purchased. Thus, after January 1999, Maine Yankee ceased purchasing insurance from NEIL and became an uninsured member.

During 2000, Maine Yankee terminated its membership in NEIL. NEIL paid to Maine Yankee a terminating distribution of $20,496,832, **(Designated Confidential Information – Protective Order No. 6)**

(End of Confidential Information) Maine Yankee credited the 2000 distribution to O&M expense, which was then reflected in the monthly bills to the three Maine owners.

Maine Yankee's Member Account Balance from 1982 through 1999 is shown on Ex-02-37 (Confidential). Without disclosing the numbers, that data response shows how the balance has grown gradually over the 18 years to the 1999 total. Thus, the $20 million payment represents **(Designated Confidential Information – Protective Order No. 6)**

(End of Confidential Information) a value that took 18 years to accumulate.

Before or after restructuring, the ratemaking treatment for an item that represents 18 years of activity should not flow through over one year.

Review of the confidential data responses, that reveal communications between and among Maine Yankee management and the Board of Directors, and between Maine Yankee and NEIL, supports a decision to treat the $20 million distribution like a capital item rather than an expense item. Moreover, the data responses indicate that Maine Yankee management and the Board of Directors (including Arthur Adelberg, then a CMP vice-president) considered alternative treatment of the NEIL distributions that would have expressly made the payment available to mitigate the stranded costs associated with Maine Yankee, but evidently never pursued the matter beyond the initial consideration.

CMP asserts that the $20 million distribution should not be flowed through to ratepayers. First, the Company argues to do so amounts to retroactive ratemaking. This argument, however, is not correct. The suggestion is not that the Commission reconcile the amount put in rates for insurance in 2000 with the amount actually spent in 2000. The point is that the distribution should not be treated as a negative insurance expense for the year 2000.

There are many items that generally accepted accounting rules require to be expensed in one year but that for ratemaking purposes are normalized or amortized over more than one year: rate case expenses, extraordinary expenses, deferred items. Indeed, there are many expenses for the Mega-case rate effective period that were deferred and will be recovered in the future. If CMP is arguing that such treatment cannot now be granted to the $20 million distribution from NEIL

because the Commission did not issue an accounting order that allowed deferral before CMP received the payment, then two responses are warranted. First, ratemaking treatment is not dependent on whether an accounting order was issued. Second, even if an accounting order was required, the failure by CMP to disclose the $20 million distribution to the Commission when the distribution was made should be found to be a failure by CMP to reasonably mitigate its stranded costs associated with Maine Yankee, and CMP's recovery of Maine Yankee's stranded costs should be adjusted accordingly. See 35-A M.R.S.A. § 3208(4).

CMP also asserts that prior to restructuring, CMP's share of the $20 million distribution would be retained by CMP because of the ARP, and not flowed back to customers. We disagree. First, CMP is not under a stranded cost ARP now. Nor was it under any type of ARP when the payment was received. In addition, extraordinary expense items, such as the ice storm, were dealt with outside of the ARP process. Gains on the sale of assets and the sale of easements were likewise not recognized in one rate year. An item that accumulated its value over 18 years seems an unlikely candidate for a flow-through in one year. CMP denies that the final distribution represented an ownership or equity-like interest in the mutual insurance company. This denial appears inconsistent with Maine Yankee's assertions to NEIL about the matter.

Regardless of whether the distribution is correctly classified as capital or expense, CMP's logic that the $20 million payment is just like any annual distribution that should be treated as a one-year reduction in property insurance expense, will ensure that the value represented by the Member Account Balance can

never be recognized in rates. If, over the course of the 18-year period, the Commission tried to allocate some portion of the Member Account Balance as a reduction to the rate effective insurance expense because Maine Yankee will eventually be paid its Member Account Balance, CMP would likely assert that it is not clear whether or when the Company would receive any such distribution and therefore the Commission should not recognize any portion of the Member Account Balance when determining the rate effective insurance expense. Then, after 18 years, when the Member Account Balance is paid to CMP, the distribution represents a one-time, non-recurring expense item that cannot be recognized in the rate effective period. The point is, over the last 18 years, it was not certain that Maine Yankee would ever receive the value represented by its Member Account Balance in NEIL, such that the value could be recognized when setting each year's insurance expense. But now 18 years later, Maine Yankee did receive its entire 18-years worth, Member Account Balance (and CMP received its share). A ratemaking result that treats the Member Account Balance just like an ordinary annual distribution is not reasonable.

b. NEIL 1999 and 2000 Annual Distributions

In August 1997, the Maine Yankee Board of Directors voted to permanently shut down the nuclear power plant. Over the next 14 to 16 months, the focus of the plant was shifted from operating to decommissioning. While the plant was still operating, Maine Yankee incurred annual O&M expenses of:

1991 – $84,395,000

1992 – $111,623,000

1993 – $115,320,000

1994 – $115,050,564

1995 – $146,476,840

1996 – $124,184,059

1997 – $173,454,577

(source: FERC Annual Reports and SEC 10-Ks)

From August 1997 through November 1998, Maine Yankee incurred almost $81 million of O&M expenses. After November 1998, Maine Yankee has incurred less than $2 million annually for O&M expenses (even excluding the NEIL distributions). (Ex-02-26)

As O&M expenses have dwindled, decommissioning expenses (or expenses paid for with funds from the decommissioning trust) have increased. Looking at the response to Ex-02-27, decommissioning expenses began in December 1997, and really took off in October 1998. From December 1997 through September 1998, $23 million was spent on decommissioning. During the next 12 months, Maine Yankee spent over $67 million on decommissioning. In the next 12 months, October 1999 through September 2000, Maine Yankee spent over $10 million on decommissioning. Over the next 11 months, Maine Yankee has spent about $100 million on decommissioning.

From these data responses and answers at the technical conferences, we know that by the beginning of 1999, virtually all expenses that had been charged as O&M expenses, including all labor by Maine Yankee employees, and all expenses associated with the Entergy management services contract, were now

accounted for as decommissioning expenses. Indeed, beginning in October 1998, the NEIL insurance was changed from an O&M expense to a decommissioning expense.

The Commission learned of this accounting change in the FERC rate case. For retail rate purposes, this change had a significant effect. Because of rate plans, the shareholders of the Maine owners absorbed the risk of variations in O&M expenses. Decommissioning expenses, however, are treated separately for ratemaking purposes, and because of the Decommissioning Trust Fund, ratepayers are at risk for decommissioning expense variations.

Thus, from the viewpoint of ratepayers, the later Maine Yankee shifted expenses from the operating expense category, to the decommissioning category, the better. We would note that by the end of 1998, the actual decommissioning project had not yet begun. Thus, it was far from clear that it was proper to classify all Maine Yankee labor expenses, and Entergy expenses as decommissioning-related in October, 1998. Admittedly, this was a gray area, however, and no doubt at some point it would be proper to re-classify all labor and other operating expenses to decommission expenses. Therefore, the Commission acquiesced in the change effective around October, 1998.

From data response OPA-03-20 (confidential), it appears Maine Yankee received annual distributions from NEIL in 1999 and 2000.[6] These distributions were accounted for as an O&M expense. At technical conferences, CMP reports that annual distributions were always accounted for in the year received, even though the amounts are based on premiums, claims and investment results of the prior

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[6]There is also return of premium in 1999.

year. Thus, the 1999 and 2000 distributions from NEIL should be accounted for as insurance expense in the year received. In the year received, insurance expenses (and evidently virtually all expenses other than DOE litigation expenses and a capitalized lease expense) were treated as decommissioning expenses.

By 1999, Maine Yankee's spending was accounted for as a decommissioning plant, not an operating plant. The 1999 and 2000 NEIL distributions should not be traced back to the operating period of the plant. Accordingly, the Decommissioning Trust Fund should be credited with those payments, or at least the ratepayers of the Maine owners should be credited with the proper share of those payments when the final decommissioning balances are tallied.

c. Other Maine Yankee Expenses

CMP has assumed that the current decommissioning collection rate will not be changed by FERC through the rate effective period. Likewise, CMP has assumed that Maine Yankee will not incur any expenses related to the Texas Low-Level Waste Compact and the Spent Fuel Trust Fund. We agree with those assumptions and agree CMP should defer the effect of any change in decommissioning collection rates and payments related to the Low-Level Waste Compact and the Spent Fuel Trust Fund.

At update time, CMP should submit Maine Yankee's most recent budget and financial forecast. It seems conceivable that Maine Yankee's projected financing costs may have changed. Also, for Exhibit Call/Dumais-2 p 1 of 5, it is not clear what O&M expenses are projected to be in the second and third year. The initial year budget is $2.8 million, $2 million of which is DOE litigation expenses. As

CMP does not expect to incur DOE litigation expenses beyond March 2003, O&M expenses should be only $800,000 for years 2 and 3. When CMP provides its update, it should submit the backup to a new Exh. Call/Dumais-2 p 1 of 5.

2. Connecticut Yankee

The prudence of the shutdown of Connecticut Yankee was litigated in its most recent FERC rate case. After the Initial Decision of the ALJ was issued, the parties reached a settlement. As part of that settlement, the parties agreed that the equity return on Connecticut Yankee investment would be 6.0%.

As a result of the Commission's Order in Phase II-A of Docket No. 97-580, CMP correctly deferred the impact of the FERC-ordered ROE on CMP's Connecticut Yankee investment compared to the Maine ROE-synchronized return that was put into rates in 97-580. CMP asks the Commission to allow it to synchronize earnings and receive its Maine authorized ROE as to both the deferral (as reflected on line 9 of Exh. Call/Dumais-3 page 1 of 12) and its going-forward Connecticut Yankee investment (as reflected on Exh. Call/Dumais-2 p 1 of 5). CMP asserts such treatment is reasonable because ultimately FERC did not find any imprudence, and even if Connecticut Yankee was imprudent, CMP was a minority owner and should not be held responsible.

At this time, the Advisors continue to believe that the proper stranded cost ratemaking treatment for CMP's Connecticut Yankee investment is the FERC-ordered ROE. The issue of the prudence of the shutdown of the plant was raised before FERC and vigorously litigated. That case was ultimately settled. The Advisors propose that the FERC-ordered ROE be applied to CMP's investment in Connecticut

Yankee as a substitute for a prudence investigation. Such a result seems more reasonable than a prudence investigation either here or at FERC and more equitable than simply ignoring the prudence issue.

As to CMP's minority ownership argument, we remain unconvinced. CMP should have to show more than mere minority ownership. We might think differently if CMP was to show that it attempted to mitigate or remedy Connecticut Yankee's imprudence (or NU's if applicable), or divest itself of its Connecticut Yankee investment while it still had value, such as a sale to NU or other shareholder.

G. Standard Offer Over Collected Balance

CMP currently estimates that there will be a standard offer overcollected balance of $4 to $5 million at the end of the current standard offer year, through February 2002. CMP has not yet provided the backup for its projected overcollection; therefore, we cannot at this point address the accuracy of CMP's estimate. We expect to do so in the Examiner's Report, at which time additional months of actual data will be available as well.

The standard offer overcollected balance reflects the difference between revenues CMP receives and the costs it incurs as the standard offer provider for medium and large non-residential customers in its service territory. CMP has been the standard offer provider for these two classes since March, 2000. The principle reason for the overcollection is that over the last several months actual market prices for Installed Capability (ICAP) have been less than the estimates upon which standard offer prices were based. In addition, since September 2001 CMP has been using the capacity credit it receives for its Hydro-Quebec tie line entitlement (the costs of which

are in stranded cost rates) toward meeting its ICAP obligation for the large standard offer class.

Much of the standard offer overcollection can be attributed to the large standard offer class for the current standard offer year, although about $0.7 million accrued from the medium class and $1.9 million from the large class during the previous standard offer year ending February, 2001. Standard offer prices for the current year were set for the large class based on estimated ICAP costs of $3.00/kW-month. This reflected the forward market prices for ICAP when standard offer prices were set last February. However, in contrast to the medium class, CMP did not purchase a full year's worth of ICAP for the large class at that time. Rather, CMP has been purchasing ICAP month-to-month, and market prices have been declining. As a result, actual ICAP costs for the large class have been significantly less than the $3.00/kW-month built in standard offer prices, and an overcollection has been accruing.

Although not addressed in its filing, in response to questions from Staff, CMP stated that it proposes to apply the standard offer overcollected balance to the ASGA, thereby reducing stranded costs.[7] We assume this would not change CMP's filed proposals regarding ASGA amortization and stranded cost allocation, although it is somewhat unclear at this point.

The primary alternatives to CMP's proposal to apply the overcollected balance to the ASGA are: (1) to apply the balance to future standard offer prices for the

[7]In CMP's October 3, 2001 filing, Mr. Call and Mr. Dumais proposed an accounting adjustment to ensure that the Hydro-Quebec Tie-Line capacity benefits offset stranded costs rather than large class standard offer costs. In response to questions from the Advisors, CMP agreed that such an accounting adjustment is unnecessary if the standard offer overcollection is applied to the ASGA.

medium and large classes; (2) to refund the balance to customers in the medium and large classes based on their standard offer purchases during the last 2 years; or (3) to apply the balance only to the stranded cost rates of customers in rate classes that correspond to the medium and large standard offer classes.[8] Of these alternatives, we prefer the third. Alternative (1) would result in lower-than-market standard offer prices, an outcome that would frustrate the competitive market. Alternative (2) would be inconsistent with the Commission's general policy that prices should be known at the time customers are making electricity consumption decisions. Alternative (3) suffers from neither of these problems and would more closely allocate the overcollection back to customers who created it than CMP's proposal would, although even this would not be particularly precise since many of the customers that would benefit were not receiving standard offer service during the time the overcollection accrued.

None of these three alternatives, however, is preferable to CMP's proposal. We discuss the reasons for this more fully in Section V. In general, though, this issue cannot be viewed in isolation. CMP's proposed treatment of the overcollection is reasonable when viewed in light of other factors that affect how the ASGA, and stranded costs generally, are allocated among customer classes. There have been various uses of the ASGA account over time. These must be considered in the aggregate. One in particular, the 8 mil mitigation, has benefited customers in the medium and large standard offer classes by an amount that far exceeds the estimated

[8]The classes that correspond to the medium standard offer class are MGS-S and MGS-P. The classes that correspond to the large standard offer class are IGS-S, IGS-P, LGS-S, LGS-P, LGS-ST and LGS-T.

standard offer overcollection. This, as well as other factors discussed in Section V, must be considered when determining how to treat the standard offer overcollection.

H. Amortization of the ASGA

The Company estimated the Asset Sale Gain Account balance at the beginning of the new stranded cost rate effective period to be $125 million. The Company recommends that this balance be amortized over a four-year period on a straight line basis. It appears, however, that when the Company's levelization adjustments are taken into account the Company actually is proposing that the amortization be done in an uneven manner over the three-year rate effective period in order to achieve levelized rates over the three-year rate effective period and to have ¼ of the current $125 million balance remaining to be utilized during rate year 2005-2006. As a general matter the Advisory Staff is in agreement with the amortization and levelization approach taken by the Company. We note below our concerns with or exceptions to the Company's approach.

1. Consistent with the discussion in Section III.F.1 the Staff would credit CMP's share of the NEIL disbursement to the return of ASGA. This would increase the account by approximately $7 million.

2. We would remove, as a deduction from the ASGA, the RWS buy-out cost (including replacement power costs) and set up a regulatory asset for RWS to be amortized over eight years over a period commensurate with the RWS contract period.

3. We would bring forward the ASGA amortization period by two months to end at the same time CMP's stranded costs drop because of the expiration of the Rumford Cogen PPA.

4. As discussed in the previous section, we would apply the standard offer overcollected balance to the ASGA.

I. <u>Levelization of Rates During the Rate Effective Period</u>

In its Phase II Analysis, CMP recommended that, after March 1, 2002, stranded cost rates remain level over the course of the 3-year stranded cost rate effective period. The Staff agrees with the Company's overall levelization approach.

One issue the Staff believes may be present in the Company's approach is the way the Company accounts for increases in sales in years 2 and 3 of the rate effective period. The Company looks at the increases on an overall company basis and then discounts the Rate Year 2 and Rate Year 3 based on the overall percentage increase when compared to Rate Year 1. Working off these discounted amounts, CMP computes a levelized revenue requirement and then calculates a levelized rate of $0.017393. The Company then calculates the revenue to be received by multiplying this levelized rate by overall sales and then balancing any difference in this amount and the stranded cost revenue requirement by adjusting the ASGA amortization.

Since different rate classes have very different stranded cost rates, not every kWh gained or lost is equal. In addition, the different classes have different projected growth rates during the 3-year rate effective period. The Staff is concerned that the Company's approach of using overall sales levels and average ¢/kWh to

calculate the impact of increased sales may not adequately account for the differing class stranded cost rates.

The Staff requests that the Company address this issue in its Reply filing and discuss whether and how this issue can be addressed as part of a 3-year levelization approach.

IV. STRANDED COST ALLOCATION

Based on CMP's proposed stranded cost amount, ASGA amortization and 3-year levelization, stranded costs for core customers would be set at $133,062,000 per year for the 3-year period beginning March 1, 2002. This is a reduction of $9,711,182 per year, or 6.8%, relative to current stranded cost rates. CMP proposes to allocate the full amount of the reduction on an across-the-board basis to only the rate classes that correspond the small standard offer class – residential, small commercial and lighting. This results in a 14.58% decrease in stranded cost rates for these classes. When combined with the standard offer price increase that will occur on March 1, 2002, on a bundled price basis, residential customers would see an increase of 4.8% and small commercial customers an increase of 4.7%. For CMP's other rate classes, which are all of the medium and large commercial and industrial (C&I) classes, CMP proposes to eliminate the 8 mil mitigation currently in their rates and make no further adjustment.[9] In other words, the stranded costs rates of CMP's medium and large C&I customers would be unchanged relative to their unmitigated levels. After March 1, 2002, the stranded cost rates of all core classes would remain constant through February, 2005.

CMP supports its recommendation to allocate the full stranded cost reduction to residential, small commercial and lighting customers as a fair apportionment of the

[9] By Orders in Docket No. 97-580 dated March 28, 2001 and May 3, 2001, the Commission directed CMP to reduce the T&D rates of medium and large C&I customers by 8 mils for the period April 15, 2001 through February 28, 2002.

benefits of the asset sale in light of the fact that $34 million of the asset sale proceeds have been dedicated to fund the 8 mil mitigation for medium and large C&I customers. CMP is not proposing that medium and large C&I customers pay back that $34 million. Rather, in recognition of the asset sale benefit these classes have already received, CMP would allocate their share of the stranded cost decrease ($5.2 million per year) to the classes that did not receive the 8 mil mitigation.

We do not disagree with CMP's conceptual approach and what we understand to be its objective, which is to allocate stranded costs in this case fairly, given past uses of the ASGA. However, we note that there are other past uses that must be considered, as well as the standard offer overcollection discussed in Section IV.G. As is the case for the $34 million spent on mitigation, for each item, when considered individually, one could argue for a direct allocation to the classes who either benefited from, or contributed to, the item at issue. In addition, the results of a cost-based allocation of stranded costs should also be considered, even if not implemented. When all the relevant factors are examined, for the reasons discussed below, we believe that some amount of the stranded cost decrease should be allocated to certain large C&I classes, most notably IGS-S and LGS-S.

First, we considered the class allocation that would result from the cost-based method endorsed by the Commission in Docket No. 97-580. Under that method, stranded costs would be directly allocated among classes "from the bottom up" based 75% on energy and 25% on demand. Although the cost-based method was not used in that case (the Commission applied a "top-down" approach instead), the results provide

an instructive comparison to CMP's proposal. For instance, the stranded cost contributions (even at unmitigated rates) of CMP's largest industrial classes, LGS-T and LGS-ST, are substantially below the contributions that would be provided if stranded costs were allocated using the cost-based method. If that method were used, an additional $5.7 million per year would be allocated to LGS-T and LGS-ST relative to CMP's proposal. By not allocating any of the stranded cost decrease to these classes, CMP's approach, at least, moves them no further away from their cost-based levels.

In contrast, for CMP's other large C&I classes, and for its medium classes, the cost-based allocation would reduce their stranded cost rates compared to current, unmitigated rates by approximately $13.6 million per year. Over the three years the stranded cost rates set in this case will be in effect, these classes would pay $40.8 million more under CMP's proposal than they would pay under the cost-based allocation. In comparison, these same classes received a $19.1 million benefit from the 8 mil mitigation. Under CMP's proposal they would pay this back (relative to a cost-based allocation) in less than one and a half years. The cost-based allocation would be particularly beneficial to the IGS-S and LGS-S classes, both of which would pay back their mitigation in less than one year under CMP's proposal compared to the cost-based allocation.

In addition to the mitigation and the results of the cost-based allocation, other factors to be considered include the standard offer overcollection that, under CMP's proposal, would flow primarily to residential, small commercial and lighting customers;[10]

[10]Since CMP is proposing a 4-year ASGA amortization there would be a small amount of the overcollection remaining when stranded costs are reset in March, 2005.

the payment to Engage as part of the small class standard offer settlement agreement; and the use of CMP's entitlements in conjunction with small class standard offer service pursuant to "linked" arrangements. CMP's current estimate of the standard offer overcollection is $4-$5 million, the payment to Engage was $4.5 million and the estimated lost entitlement sale revenue is $3.5 million.[11] The latter two items have resulted in benefits for small class standard offer customers; there are valid arguments that the costs should be allocated to those classes as well. Similarly, the standard offer overcollection could be allocated to the medium and large classes, particularly the large.

In summary, each of these items, the $34 million cost of mitigation, the $4-$5 million standard offer overcollection, the $4.5 million Engage payment and the $3.5 million lost entitlement value could be directly allocated to the classes that benefited or contributed. Or, as CMP proposes, these items could be considered when evaluating the equity of future stranded cost allocations. If we look at just these items without taking into account the results of a more cost-based stranded cost allocation, CMP's proposal to allocate the entire stranded cost reduction to the classes who have not received the mitigation appears reasonable. The additional reduction these classes would receive ($5.2 million per year for three years) would reasonably balance the difference between the mitigation and other past uses of the ASGA. However, we believe that the results of a cost-based stranded cost allocation should also be considered. As discussed above, we find that these results support an allocation of

[11]This reflects the difference between the actual sale price to Engage and the highest stand-alone bid received for these entitlements multiplied by the quantity during the two-year entitlement sale period.

some of the stranded cost decrease to CMP's distribution voltage industrial classes, particularly IGS-S and LGS-S.

We ask CMP to comment on this in its response to the Bench Analysis and to provide the results of such an allocation.

Dated: November 14, 2001

Submitted by;

S/
Charles Cohen on behalf of
The Advisory Staff:

James Buckley
Faith Huntington
Angela Monroe
Richard Kivela

Bench Analysis Appendix (Redacted)

Appendix Table 1a

	Residential Real Price				Residential 4 Year Moving Average Price			
	CMP	Percent Change	Revised	Percent Change	CMP	Percent Change	Revised	Percent Change
1995	12.62		12.62		11.95		11.95	
1996	12.80	1.38%	12.80	1.38%	12.35	3.38%	12.35	3.38%
1997	12.91	0.93%	12.91	0.93%	12.69	2.70%	12.69	2.70%
1998	13.05	1.08%	13.05	1.08%	12.85	1.27%	12.85	1.27%
1999	13.14	0.62%	13.14	0.62%	12.98	1.00%	12.98	1.00%
2000	12.27	-6.58%	12.27	-6.58%	12.84	-1.01%	12.84	-1.01%
2001	11.68	-4.83%	11.68	-4.83%	12.53	-2.41%	12.53	-2.41%
2002	11.77	0.80%	11.35	-2.82%	12.21	-2.56%	12.11	-3.40%
2003	11.73	-0.35%	10.93	-3.70%	11.86	-2.88%	11.56	-4.55%
2004	11.50	-2.00%	10.47	-4.21%	11.67	-1.64%	11.11	-3.90%
2005	11.39	-0.88%	10.26	-2.04%	11.60	-0.61%	10.75	-3.20%

Appendix Table 2

	Commercial Real Price				Commercial 4 Year Moving Average Price			
	CMP	Percent Change	Revised	Percent Change	CMP	Percent Change	Revised	Percent Change
1995	10.416		10.416		10.222		10.222	
1996	10.336	-0.77%	10.336	-0.77%	10.339	1.15%	10.339	1.15%
1997	10.147	-1.83%	10.147	-1.83%	10.355	0.15%	10.355	0.15%
1998	10.073	-0.73%	10.073	-0.73%	10.243	-1.08%	10.243	-1.08%
1999	9.902	-1.70%	9.902	-1.70%	10.115	-1.25%	10.115	-1.25%
2000	9.421	-4.86%	9.421	-4.86%	9.886	-2.26%	9.886	-2.26%
2001	10.634	12.87%	10.635	12.88%	10.008	1.23%	10.008	1.23%
2002	10.057	-5.42%	9.741	-8.40%	10.004	-0.04%	9.925	-0.83%
2003	9.602	-4.53%	9.006	-7.55%	9.928	-0.75%	9.701	-2.26%
2004	9.432	-1.77%	8.470	-5.95%	9.931	0.03%	9.463	-2.45%
2005	9.386	-0.48%	8.200	-3.18%	9.619	-3.14%	8.854	-6.43%

Appendix Table 3

	Industrial Real Price				Industrial 4 Year Moving Average Price			
	CMP	Percent Change	Revised	Percent Change	CMP	Percent Change	Revised	Percent Change
1995	8.24		8.24		8.47		8.47	
1996	8.06	-2.11%	8.06	-2.11%	8.37	-1.17%	8.37	-1.17%
1997	7.77	-3.62%	7.77	-3.62%	8.19	-2.15%	8.19	-2.15%
1998	7.56	-2.66%	7.56	-2.66%	7.91	-3.49%	7.91	-3.49%
1999	7.36	-2.62%	7.36	-2.62%	7.69	-2.75%	7.69	-2.75%
2000	7.63	3.61%	7.63	3.61%	7.58	-1.40%	7.58	-1.40%
2001	8.61	12.82%	8.61	12.82%	7.79	2.77%	7.79	2.77%
2002	7.26	-15.62%	6.90	-19.82%	7.72	-0.96%	7.63	-2.12%
2003	6.86	-5.60%	6.34	-8.22%	7.59	-1.64%	7.37	-3.37%
2004	6.73	-1.86%	5.90	-6.93%	7.37	-2.97%	6.94	-5.88%
2005	6.71	-0.26%	5.78	-2.03%	6.89	-6.44%	6.23	-10.21%

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(Designated Confidential Information – Protective Order No. 2)

(Designated Confidential Information – Protective Order No. 2)

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(End of Confidential Information)